

**DIRECT TESTIMONY
OF
W. KELLER KISSAM**

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DIRECT TESTIMONY OF

W. KELLER KISSAM

ON BEHALF OF

DOMINION ENERGY SOUTH CAROLINA

DOCKET NO. 2020-125-E

**Q. PLEASE STATE YOUR FULL NAME, BUSINESS ADDRESS AND
OCCUPATION.**

A. My name is W. Keller Kissam and my business address is 220
Operation Way, Cayce, South Carolina. I am President, Electric Operations,
Dominion Energy South Carolina, Inc. (the "Company" or "DESC").¹

**Q. PLEASE STATE YOUR EDUCATIONAL BACKGROUND AND
EXPERIENCE.**

A. I am a summa cum laude graduate of The Citadel, The Military
College of South Carolina where I also received an Honorary Doctorate of
Business. My utility career began in 1988 when I joined SCANA
Corporation ("SCANA") as a New Utility Professional and then held a
number of positions in gas administration and gas supply until 1994, when I

¹ In April 2019, South Carolina Electric and Gas Company ("SCE&G") changed its name to Dominion Energy South Carolina, Inc. as a result of the acquisition of SCANA Corporation by Dominion Energy, Inc. For consistency, I use "DESC" to refer to the Company both before and after this name change.

1 was named Vice President, South Carolina Pipeline Corporation, now known
2 as Dominion Energy Carolina Gas Transmission. In 1996, I was named Vice
3 President, Gas Operations, DESC; in 2003, Vice President Electric
4 Operations, DESC; in 2011, President, Retail Operations, DESC; and in
5 2017, Chief Operating Officer and President of Generation, Transmission
6 and Distribution. Upon the merger of SCANA and Dominion Energy in
7 2019, I became President, Electric Operations, DESC with responsibilities
8 for Transmission, Distribution and Non-Nuclear Power Generation. I am a
9 Board Member and former President of the Board of Southeastern Electric
10 Exchange, and Chairman of the Board of the Central South Carolina
11 Economic Development Alliance.

12 **Q. HAVE YOU PREVIOUSLY PRESENTED TESTIMONY BEFORE**
13 **THE PUBLIC SERVICE COMMISSION OF SOUTH CAROLINA**
14 **(THE “COMMISSION”)?**

15 A. Yes, I have testified in several proceedings before this Commission.

16 **Q. WHAT IS THE PURPOSE OF YOUR TESTIMONY IN THIS**
17 **PROCEEDING?**

18 A. The purpose of my testimony is to provide an overview of the
19 operating results of the DESC electric system focusing primarily on
20 investments made to promote safety, improve reliability, ensure resiliency,

1 and comply with regulatory requirements while achieving the highest level
2 of involvement and communications with customers and the communities we
3 serve. I also make two specific requests of the Commission to support
4 continued improvement in safety, reliability and resiliency. The first is
5 restoration of collection of the storm damage reserve going forward in
6 addition to the amortization of the cumulative balance in the storm reserve
7 as it exists today. Second is creating an accrual account for vegetation
8 management expenses for both transmission and distribution electric
9 operations.

10 **I. OPERATIONAL METRICS FOR SAFETY, RELIABILITY**
11 **AND RESILIENCY**

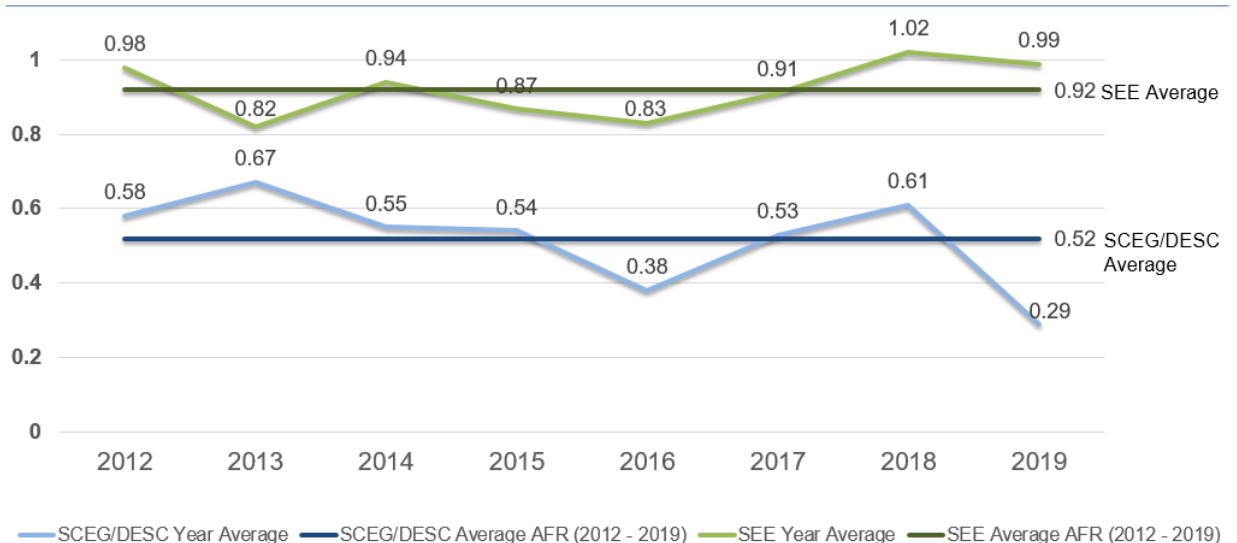
12 **Q. WHAT ARE DESC'S RECENT OPERATING RESULTS RELATED**
13 **TO SAFETY, RELIABILITY AND RESILIENCY OF ITS ELECTRIC**
14 **SYSTEM?**

15 A. **Safety.** Everything starts with employee safety and everything
16 centers on employee safety. If employees develop unrelenting focus,
17 concern and care for their own personal safety as well as the safety of their
18 fellow employees, then those attitudes will translate into focus, concern, and
19 care for customers and communities. The electric utility industry is one of
20 the top ten industries in the United States for fatalities per total hours worked.
21 In our industry, safety rules are written in burn center visits and blood.

The Accident Frequency Ratio (“AFR”) is the ratio of the as-recorded accident events as defined by the Occupational Safety and Health Administration (“OSHA”) per total hours worked. AFR is the key metric of safety across the industry. The following graph compares the AFR for DESC for the years 2012-2019 to a Southeast geographic average among like utility companies.

Graph A: Accident Frequency Rate

DESC & SEE Final Average AFRs



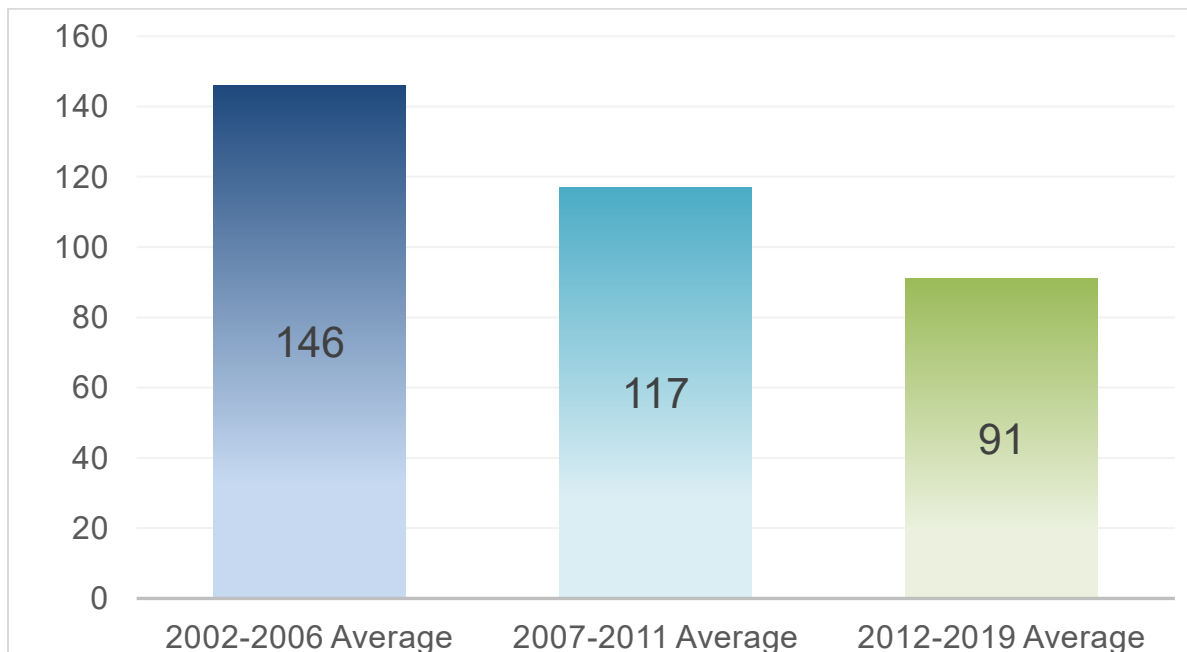
These statistics show the Company’s safety culture is top-quartile. Its performance for 2012-2019 resulted in forty-five percent fewer accidents on average compared to its Southeast utility peers. This is extraordinary success. The Company lives and breathes this safety focus, and it drives our operational performance in all areas.

1 **Reliability**. In my thirty-two years of utility experience, the highest
2 priority voiced by customers has always been “keep my lights on!”
3 Customers say this consistently and resoundingly. Reliability is what matters
4 to them most.

5 Reliability means preventing outages. You prevent outages by
6 vegetation management, which is right-of-way patrolling, side-trimming,
7 dead tree removal, understory management through selective herbicide
8 application, and educating property owners on the selection of proper
9 vegetation to be planted under or adjacent to power lines. You also prevent
10 outages by having a disciplined system for regularly inspecting electrical
11 poles, transformers, and hardware and replacing any that are a reliability risk.

12 SAIDI, the System Average Interruption Duration Index, is the
13 benchmark for measuring our success in keeping the lights on from year to
14 year. It is the number of minutes on average a customer on our system is
15 without power. The lower the score the better. Graph B shows the
16 Company’s recent SAIDI scores.

17

Graph B: Average SAIDI Score

From 2002-2006 to 2007-2011, DESC's reliability improved by twenty percent. From 2007-2011 to 2012-2019, DESC's reliability improved by another twenty-three percent. In 2019, DESC's SAIDI of 77.8 minutes was at an historically low level. As reported by the State Energy Office, DESC provided its customers a level of reliability in 2019 that was forty-nine percent better than the other regional investor-owned utilities evaluated by that office.²

These SAIDI scores reflect years of steadily increasing attention to vegetation management and spending to execute vegetation management

² <http://energy.sc.gov/node/3065>

1 plans. We have refined our approach over a decade of study and trials and
2 are employing a mix of the most cutting edge techniques in the industry to
3 manage vegetation effectively in our service territory, which has one of the
4 most intense growth rates for vegetation in the United States. Vegetation
5 management requires constant attention because the Company's service
6 territory has high rainfall and one of the longest growing seasons (based upon
7 first frost to last frost) in the continental United States, promoting vigorous
8 vegetative growth.

9 The Company performs vegetation management on a five-year cycle
10 for distribution circuits. We use a varied cycle for transmission assets, which
11 depends upon specific plant and tree species in the area. There is follow-up
12 herbicide application annually for select distribution circuits and a three-year
13 herbicide cycle for transmission rights-of-way. Implementing this cycle with
14 discipline and consistency is the key to effective vegetation control.

15 Distribution lines and other assets are inspected on a ten-year cycle.
16 Poles are sounded to ensure that shelling or rot are not compromising their
17 integrity. (A pole can rot from the inside and appear sound on visual
18 inspection.) In addition, other components such as insulators, fuses,
19 switches, transformers, wires, and hardware are inspected to ensure they are
20 in good operating condition. New assets are installed where old assets are

1 not up to standard. It takes effort to identify equipment that is failing and it
2 costs money to replace it, but we are doing both.

3 **Resiliency.** Resiliency is the ability to recover quickly from
4 damaging events and disruption. On any given day, electric infrastructure in
5 South Carolina is disrupted by falling limbs and trees, car hit pole events,
6 animals bridging connectors, lightning and wind. However, the true test of
7 our system's resiliency occurs in hurricanes, ice storms, and tornados.

8 The following table lists the seven major storms that have impacted
9 DESC's service territory since 2014. It shows each storm, the number of
10 customers who were without power at the end of the storm, and the days to
11 restore service. For the Company, restoration is not complete until in each
12 county affected at least 95% of all customers have been restored.

13 (Table begins on following page)

Table A: Major Storm Outages and Restoration 2011-2020³
DESC Outage Information 2011-2020

Event	Dates	Total Customers Out	Days to Restore Service
2014 Winter Storm Pax	2/12/14 – 2/19/14	151,700	7
Hurricane Matthew	10/7/16 – 10/16/16	313,300	9
Hurricane Irma	9/11/17 – 9/14/17	173,300	3
Hurricane Florence	9/14/18	7,500	1
Hurricane Michael	10/11/18 – 10/12/18	68,800	2
Hurricane Dorian	9/4/19 – 9/8/19	186,400	4
April 2020 TORNADOS	4/13/20	65,800	1

The table shows that winter storms, hurricanes, and tornados are a recurring threat to South Carolina and its electric infrastructure. But because of the work done to build resiliency into DESC's transmission and distribution system, the number of customers whose lights go out in a major storm is trending down, and the time it takes to get them reconnected is being reduced.

Vegetation management plays a critical role in resiliency as well as reliability. Where rights-of-way have been poorly maintained, the likelihood of damage in a major storm is greater. Restoring service afterwards is slower, more difficult and much more dangerous to our crews. Our commitment to

³ Customer outages in an event can be reported in two ways. Total Customers Affected is the cumulative total of customer outages experienced during the event. Peak Customer Outages is the highest number of customer outages at any point in the event.

1 vegetation management has had a major impact on the resiliency of our
2 system when disasters strike, and it also affects the safety risks to our crews.
3 A major danger in storm restoration is releasing the stored energy when
4 removing partially fallen trees that have become entangled in power lines.
5 Poor vegetation management can lead to dangerous situations in the field.

6 When a major storm has disrupted service, restoration of power
7 becomes the top priority in the State. The stakeholders are many and varied.
8 The Company works closely with the South Carolina Office of Regulatory
9 Staff (“ORS”) and its Executive Director to ensure that the Executive
10 Branch, National Guard and state and local officials at all levels have up to
11 date information on outages and restoration efforts. ORS helps us ensure that
12 the needs of the crews working storm restoration are effectively
13 communicated to those stakeholders. ORS plays the leading role in
14 communicating and coordinating information flows to the South Carolina
15 Emergency Management Division and executive branch of the South
16 Carolina government in these events. We have an excellent working
17 relationship with ORS and support Ms. Edwards and her team fully in this
18 work.

19 **Q. CAN YOU PROVIDE EXAMPLES OF SYSTEM RESILIENCY IN**
20 **THE FACE OF STORMS?**

1 A. In September of 2019, Hurricane Dorian brought sustained wind
2 speeds of over 85 miles per hour to the Charleston area, 10 inches of rain to
3 McClellanville, and 17 hours of winds that exceeded tropical storm force in
4 Charleston. In all, there were more than 279,000 Customers Affected
5 (customers who lost service at one point or another in a storm), representing
6 80% of all Charleston customers, with service interruptions peaking on the
7 afternoon of September 5, 2019. There were approximately 186,400
8 customers without power when the storm ended. All lights were back on by
9 Sunday evening, a little more than three days later.

10 On April 13, 2020, 21 tornadoes touched down in South Carolina, four
11 of which were classified as EF3-strength with winds up to 165 miles per hour
12 and one which was classified as an EF4 tornado with winds up to 200 miles
13 per hour. It was the most prolific day of tornado activity in South Carolina in
14 the last 35 years. Within 24 hours our crews had restored 96% of the 117,000
15 of our customers who lost service at one point or another during that storm.
16 There were 65,800 customers without power after the storm system had
17 passed. Within two days, storm restoration was complete.

18 An even more recent example of resilience is what happened when
19 Hurricane Isaias sent tropical storm force winds through our coastal service
20 territory including Charleston, Folly Beach, Isle of Palms, Dewees Island and

McClellanville. Sustained wind speeds were 52 miles per hour at Folly Beach and as high as 72 miles per hour in McClellanville. Yet at the peak of the outage, less than 250 of our customers were without power.

Storms and storm restoration are the ultimate test of our system and our people. However big the challenge or however long it takes, our crews work around the clock until the last customer is restored. The Company is proud of its record for safety, reliability and resiliency, which is exceptional.

II. INVESTMENT IN ELECTRIC SYSTEM

Q. WHAT HAS DESC INVESTED IN ITS ELECTRIC SYSTEM SINCE THE LAST PROCEEDING?

A. Since the last proceeding, DESC has invested a total of \$3.2 billion, before considering depreciation and other offsets, in the assets required to provide safe, reliable and economical electric service to electric customers. This investment in the generation system does not include the purchase of Columbia Energy Center (“CEC”), which is not included in this rate request. A breakdown of this investment is shown in Table B, below.

Table B: Breakdown of Investment in Electric System

Generation System	\$878 million
Transmission System	\$1.0 billion
Distribution System	\$1.1 billion
Corporate Assets (including information technology and fleet maintenance)	\$198 million
TOTAL INVESTMENT	\$3.2 billion

III. DESC'S POWER GENERATION OPERATIONS

Q. PLEASE DESCRIBE THE COMPANY'S POWER GENERATION OPERATIONS.

A. During the period from 2012 through 2019, DESC Power Generation strategically focused its capital expenditures and has achieved demonstrated improvements in reliability, safety performance, and environmental stewardship. During this period, our Power Generation operations transitioned from a fuel source mix that had been historically dominated by coal to one now led by natural gas. Table C below provides a comparison of DESC's generation resource mix from 2012 to 2019.

Table C: DESC Power Generation Supply Mix

Generating Resources by Fuel Type								
Fuel Type	Installed Capacity (Summer)	2012	2019	% Change	Actual Generation	2012	2019	% Change
Natural Gas - Combined-Cycle, Gas-Fired Steam, Simple-Cycle Combustion Turbines		30%	39%	30%		29%	48%	69%
Coal - incl. Dual-Fuel Coal		45%	26%	-41%		49%	23%	-54%
Nuclear		11%	10%	-12%		19%	22%	18%
Hydroelectric - Conventional and Pumped Storage		14%	12%	-13%		3%	3%	3%
Utility-Scale Solar		0%	12%	N/A		0%	4%	N/A

The transition from coal to natural gas generation includes the retirement of the 385-megawatt coal-fired Canadys Station, the conversion of McMeekin Station and steam Unit 3 at Urquhart Station from coal to natural gas, and the restoration of dual-fuel (coal and natural gas) firing capability at Cope Station. In 2018, DESC Power Generation added the

1 CEC, a 504-megawatt combined-cycle natural gas generating facility, to the
2 fleet as a utility-owned and operated asset.⁴ At the end of 2018, DESC sold
3 its interest in the coal/biomass-fueled generator at the Kapstone facility in
4 North Charleston. The transition from coal to gas has been a major driver
5 toward improvements in all operating indicators, including lower emissions
6 and declining fuel costs for our customers.

7 Total spending on additions in Power Generation for the review
8 period was \$878 million.

9 **Q. HOW HAS THE COMPANY IMPROVED THE RELIABILITY OF**
10 **ITS POWER GENERATION OPERATIONS?**

11 A. During the eight-year review period, key reliability indices improved
12 due to strategic investments made to improve existing plant assets. Major
13 investments included:

- 14 • Boiler Tubes/Pressure Piping
- 15 • Cyber Security/Digital Controls Upgrades
- 16 • Extreme Weather Preparedness/Freeze Protection
- 17 • Turbine-Generators
- 18 • Dual-Fuel/Natural Gas Conversions

⁴ The purchase of CEC is not included in this rate request.

1 The DESC Power Generation group practices a reliability-centric
2 maintenance philosophy. It is centered around a mix of corrective
3 maintenance, targeted capital investments and improvements, and on-going
4 preventive and predictive maintenance activities. Major plant outages are
5 coordinated and planned years in advance to ensure schedule and budget
6 compliance. The Major Maintenance Accrual (“MMA”) mechanism has
7 been extremely effective in allowing DESC to plan and execute major
8 turbine-generator maintenance outages as necessary and appropriate,
9 particularly with the shift during the review period from conventional coal-
10 fired generation to significantly greater amounts of combined-cycle natural
11 gas generation. The accrual facilitates Power Generation keeping its steam
12 and gas turbine-generators on their OEM-prescribed maintenance intervals,
13 which in turn helps to ensure their availability and reliability and helps DESC
14 minimize its power generation costs.

15 **Q. CAN YOU PROVIDE AN EXAMPLE OF A RELIABILITY**
16 **PROJECT?**

17 A. Yes. An example of a project undertaken since the last test year to
18 enhance reliability is the replacement of the Generator Step-up Transformer
19 (“GSU”) on Unit 1 at Wateree Station in 2013. The GSU transformer was
20 original plant equipment and was approaching its end of life after 40 years in

1 service as indicated by excessive gas production. As the transformer cannot
2 be repaired during a normal scheduled outage, the transformer was replaced
3 to minimize the potential out of service time for Wateree Unit 1 in the event
4 of a failure. A photo of the new GSU transformer being delivered to the site
5 can be seen below in Photo 1. It has performed flawlessly for the last seven
6 years.

7 **Photo 1: Wateree Station Unit 1 Generator Step-Up Transformer Delivery**

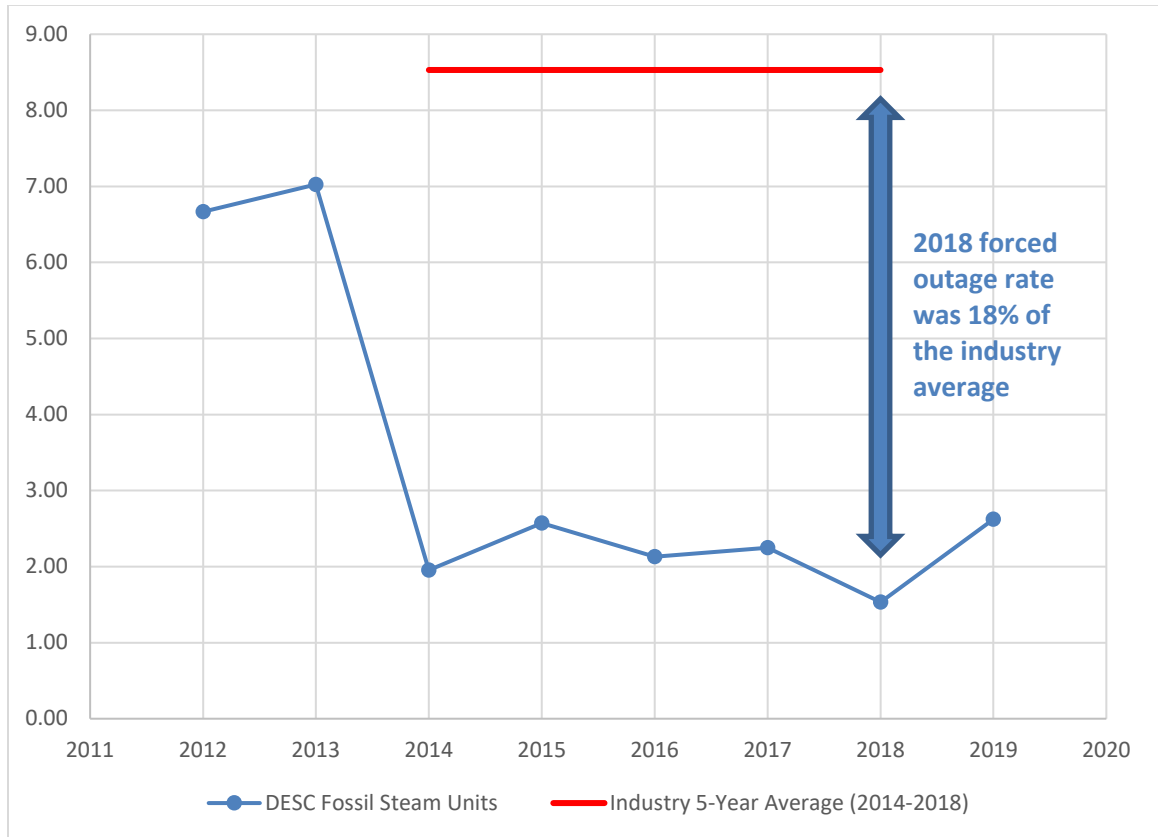


8
9 **Q. HAVE THERE BEEN MEASURABLE IMPROVEMENTS IN THE**
10 **RELIABILITY OF THE COMPANY'S POWER GENERATION**
11 **OPERATIONS?**

12 **A.** Yes. As a result of the investments made by the Power Generation
13 group, key reliability indicators have improved. Graph C illustrates the
14 improvement in performance over time of our fossil steam generating fleet

as measured by the reduction in Forced Outage Rate (“FOR”). FOR is a measure that indicates the amount of time in a year that a generator is unexpectedly unavailable for service.

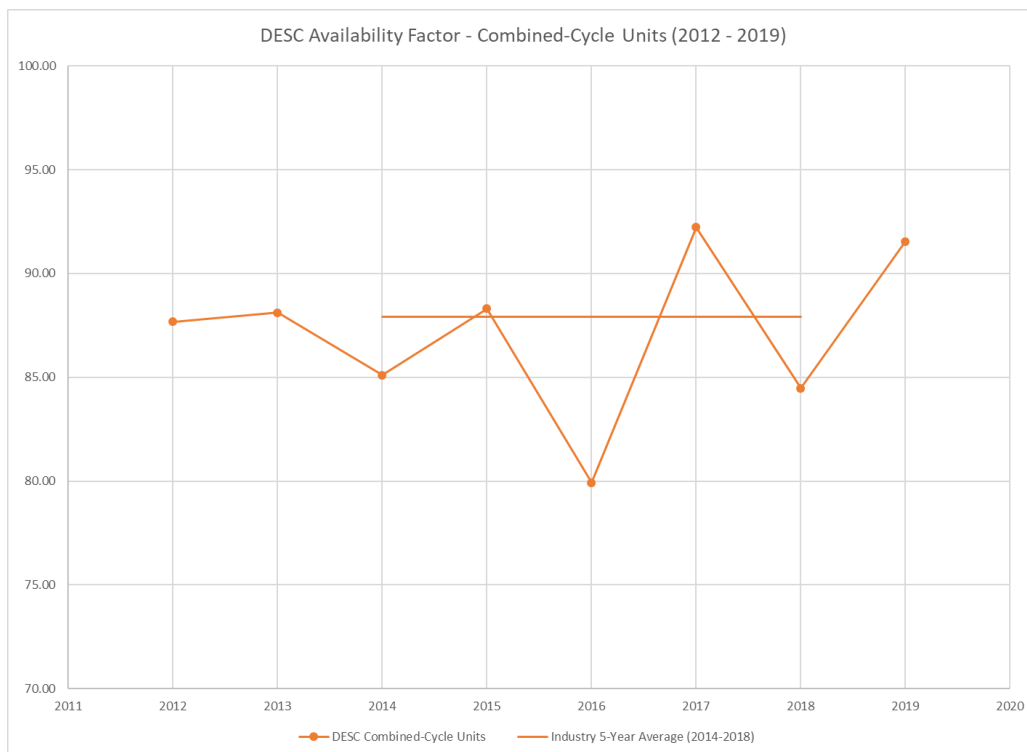
Graph C: DESC Power Generation Annual Forced Outage Rate



The forced outage rate for DESC’s fossil steam units of 6.67% in 2012 declined to 2.62% by 2019. This rate compares favorably to the five-year industry average for fossil steam units of 8.53% (for the period 2014 to 2018) as reported to the North American Electric Reliability Corporation (“NERC”) Generating Availability Data System (“GADS”) database.

During the review period, our Availability Factor (“AF”) performance for combined-cycle units remained comparable with the five-year industry average for the period 2014 to 2018 as reported to GADS. AF is another important operating metric that measures the amount of time in a year that a generator is available for service and not in a scheduled or unscheduled outage. DESC Power Generation’s performance is shown in Graph D below.

Graph D: DESC Power Generation Annual Availability Factor



The reduction in the factor during the period from 2016 to 2019 is primarily attributable to major scheduled outages that were undertaken at Wateree and Williams Stations to implement large capital projects to enhance reliability, safety and environmental performance. During the

1 review period, DESC undertook its first major inspections of the GE 7F
2 combustion turbines at Jasper and Urquhart stations and a major outage for
3 inspections and equipment upgrades at CEC following purchase of the
4 facility by DESC in 2018. These scheduled outages largely account for the
5 periodic reductions in availability shown on the chart.

6 **Q. HOW HAS THE COMPANY IMPROVED THE SAFETY OF ITS**
7 **POWER GENERATION OPERATIONS?**

8 A. Employee safety in the Power Generation group requires significant
9 employee and management engagement given the inherent dangers of the
10 industry. A key safety performance indicator is the OSHA AFR, which was
11 1.09 for DESC Power Generation in 2012 and 0.00 in 2019. DESC's marked
12 improvement in its safety performance is largely credited to plant betterment
13 investments and a cultural transition from viewing safety through lagging
14 performance indicators and post-incident responses to a proactive mindset
15 utilizing "leading indicators" to identify potential hazards and mitigate risks.
16 In 2012, employees reported only three "hazard/near miss" reports. In 2019,
17 546 such reports were documented.

18 Arc flash safety and mitigation has been a key safety focus for utilities
19 in the United States over the last decade, including DESC. Arc flash is the
20 explosive release of heat and light when an electric current arcs to ground or

1 another voltage phase. It can cause major injury to workers operating
2 switchgear in generation stations. Since 2012 DESC has spent \$13 million to
3 address and mitigate arc flash and short circuit hazards in its non-nuclear
4 Power Generation facilities.

5 We have replaced older medium and low voltage switchgear that can
6 be a source of arc flash with safer, technologically-advanced new designs.
7 Significant switchgear and other electrical upgrades were undertaken since
8 2011 at Fairfield Pumped Storage, McMeekin Station, Saluda Hydro, and
9 Wateree Station to minimize the risk of arc flash. Photo 2 shows a new 480V
10 motor control center that was installed on Wateree Station Unit 1. This new
11 equipment operates controls remotely to isolate workers from the switchgear
12 that could cause arc flash. It replaced the original equipment—manually-
13 operated electrical gear that was approaching 50 years of age—providing a
14 significant improvement in safety to protect our personnel and to improve
15 the generating unit's reliability.

16 (Photo 2 on following page)

1 **Photo 2: Wateree Station Unit 1 480V Motor Control Center Replacement**



2

3 **Q. WHAT STEPS HAS THE COMPANY TAKEN TO REDUCE IMPACT**
4 **ON THE ENVIRONMENT FROM ITS POWER GENERATION?**

5 A. Dominion Energy has a strong commitment to environmental
6 stewardship. As seen in Table D, investments made in air pollution controls
7 at our facilities to ensure environmental compliance, coupled with the shift
8 from coal to natural gas-fired generation, have resulted in substantial
9 reductions in emissions as reported to the South Carolina Department of
10 Health and Environmental Control (“SC DHEC”) and the United States
11 Environmental Protection Agency (“EPA”).

12

**Table D: DESC Power Generation Air Emissions as Reported
by Continuous Emissions Monitoring Systems (“CEMS”)**

	SO₂ (tons)	NO_x (tons)	CO₂ (tons)	Hg (lbs)
2012	27,890.80	9,162.50	14,944,855.30	144.3
2013	19,305.80	7,012.30	12,507,928.80	109.5
2014	16,768.50	7,608.70	13,984,608.60	69.9
2015	5,057.30	5,755.40	12,849,506.00	21.1
2016	2,659.50	5,414.60	11,567,440.10	12
2017	2,710.20	5,586.50	11,783,756.90	15.8
2018	2,529.90	5,779.60	12,683,119.00	20.8
2019	1,360.40	4,395.00	8,832,370.10	22.2
% Change	-95.1%	-52.0%	-40.9%	-84.6%

Since 2012, sulfur dioxide (“SO₂”) emissions have been reduced by over 95%, nitrous oxide (“NO_x”) emissions have been reduced by 52%, carbon dioxide (“CO₂”) emissions have been reduced by over 40%, and mercury (“Hg”) emissions have been reduced by over 84%.

In furtherance of its commitment to environmental stewardship, DESC has acted proactively to deal with legacy coal ash issues. DESC has been an industry leader in the country in its approach to legacy coal ash storage facilities and has been recognized by the environmental community

1 for its actions and commitments. As part of these commitments, all DESC
2 ash storage facilities have been upgraded to Class III landfill standards, ash
3 ponds at McMeekin and Wateree station have been certified as closed by SC
4 DHEC, and the ash storage facilities at the former Canadys Station site are
5 being actively mitigated in conjunction with SC DHEC permitting.

6 In regards to the Wateree Station, in 2011 DESC and SC DHEC
7 voluntarily reached an agreement (“2011 Agreement”) to remove the ash and
8 close the pond by January 1, 2021. To complete the complex process, DESC
9 had to convert waste handling systems to limit discharges, develop new Class
10 III lined landfill capacity and new wastewater management features, close
11 out other miscellaneous low volume waste ponds, and develop on-site soil
12 borrow practices and management facilities, all while contending with legal
13 challenges. This included the installation of a first of its kind bottom ash
14 conversion process where all water is recycled. The foresight and master
15 planning for the project also enabled DESC to realize some of the most cost-
16 effective ash pond closure costs in the industry.

17 Although the schedule for the closure of the pond was complex and
18 relied on the development of many ancillary new site facilities and “Balance
19 of Plant” modifications, in August 2012, DESC signed an agreement (“2012
20 Agreement”) with Catawba Riverkeeper that accelerated the closure date by

1 one year, to December 31, 2020. To minimize costs, DESC entered into an
2 arrangement with its in-house construction services group, Heavy Equipment
3 Operations (“HEO”), to allow ash removal to be done using in-house
4 resources that were already available on our system. By coordinating HEO’s
5 work with the schedule for Balance of Plant modifications, HEO was able to
6 schedule ash removal during slow times when its equipment was not needed
7 elsewhere on the system, avoiding the mobilization and contractor fees that
8 would have been required if a third party contractor had been used.

9 In 2016, a dry fly ash handling system was installed, thus ending all
10 wet sluicing of ash to the Ash Pond. The Clean Closure of the Wateree Ash
11 Pond was completed in November 2019. From initial project development in
12 2012 to present, more than 3.5 million cubic yards of ash were removed from
13 an ash pond adjacent to a major river and either recycled or placed dry in a
14 lined landfill. This project was completed at a fraction of the costs that would
15 have been incurred had the project been delayed or accomplished with
16 outside contractors and with no OSHA recordable accidents. Photo 3 shows
17 the Wateree Station ash impoundment in early 2016, while Photo 4 shows
18 the impoundment in late 2019 following its cleanout and closure.

19 (Photos begin on following page)
20

Photo 3: Wateree Station Ash Impoundment (January 26, 2016)



Photo 4: Wateree Station Ash Impoundment (November 21, 2019)



1 In sum, DESC Power Generation operations during the test period
2 were marked by continuous improvement in areas of reliability, safety
3 performance, and environmental stewardship. DESC has made targeted
4 investments to promote improvement in each of these areas, with clearly
5 demonstrable results. The investments that have been made have positioned
6 the Power Generation group to shift to lower cost and cleaner-burning natural
7 gas, supported decarbonization and environmental protection, and prepared
8 DESC to continue providing economical and reliable service to our
9 customers.

10 **IV. DESC'S INVESTMENTS IN TRANSMISSION SYSTEM**

11 **Q. HOW DOES THE COMPANY DETERMINE ITS INVESTMENTS IN**
12 **ELECTRIC TRANSMISSION ASSETS?**

13 **A. Energy Policy Act of 2005.** In 2003, 55 million people lost electric
14 service for a substantial period of time as a result of a series of failures that
15 began when a power line sagged into foliage on an overgrown right-of-way.
16 The blackout cascaded across the national transmission grid, and its effects
17 were concentrated in the northeastern United States and Canada.⁵ As a result,
18 Congress enacted the Energy Policy Act of 2005 and authorized the Federal

⁵ Photos of the effect of the outage can be found here:

<https://www.theatlantic.com/photo/2018/08/photos-15-years-since-the-2003-northeast-blackout/567410/#:~:text=On%20August%2014%2C%202003%2C%20a,blackout%20in%20North%20A%20merican%20history.>

1 Energy Regulatory Commission (“FERC”) to issue mandatory electric
2 reliability standards. Additionally, Congress designated the NERC as the
3 statutory Electric Reliability Organization (“ERO”) to enforce these
4 standards. The ERO not only has authority to enforce such standards, but
5 may also levy fines up to \$1 million per day per event for non-compliance.
6 These standards apply to all aspects of planning, operating, maintaining, and
7 constructing the Company’s transmission assets, to include very prescriptive
8 vegetation management activities, personnel training, inspection and repair
9 of facilities, and protection of such electrical transmission assets from both
10 physical and cyber threats.

11 These federal regulations, applied through the NERC Planning
12 Standards and implemented by DESC’s Internal Planning Criteria, require
13 that DESC’s electric transmission system must be shown to be able to
14 withstand specific events on the electrical system while continuing to serve
15 firm load to its direct customers and firm transmission services provided to
16 other parties. The system must be continually modeled to ensure the
17 reliability of the Company’s transmission system as well as its
18 interconnections to neighboring utilities to maintain a stable and reliable
19 national electric grid. As a result of this planning criteria, coupled with
20 growth across the Company’s service territory, the Company is continually

1 required to make large capital investments to not only expand capacity, but
2 to also maintain the present system's operating integrity and comply with
3 federal regulations.

4 **System Operating Limitation ("SOL").** DESC's Transmission
5 Planning Department studies and models the Company's transmission
6 system and determines which electric lines and associated infrastructure are
7 subject to failure and resulting grid impacts as a result of certain
8 contingencies such as loss of a generator, transmission line, transmission
9 transformer, or certain other transmission substation equipment. Upon
10 analyzing such conditions, a planning memorandum is issued with an actual
11 date specific for construction to be concluded by the Company's
12 Transmission Planning Department. Then, Power Delivery Engineering,
13 Siting, and Construction must permit, design, site, and construct the new
14 electrical infrastructure by the mandatory date in order to comply with FERC
15 planning criteria.

16 **Q. HOW HAVE THE PLANNING CRITERIA RESULTED IN**
17 **CONSTRUCTION OF POWER DELIVERY ASSETS AT DESC**
18 **SINCE THE LAST TEST YEAR?**

19 A. Under the planning criteria, for the period of 2012-2020, DESC
20 constructed 882 miles of transmission lines and forty-three substations,

1 fourteen of which were for solar farms within its service territory. New
2 construction work was performed by Company transmission crews,
3 contractors working on competitive bids, and contractors working under
4 engineering, procurement, and construction (“EPC”) contracts. In addition to
5 this construction, the Company also patrolled, inspected, and initiated repair
6 of existing transmission assets.

7 Of the transmission lines constructed, 493 circuit miles were 230
8 kilovolt (“kV”) lines. 230 kV lines typically route from generation sources
9 and interconnect to the regional electrical grid. Because they are rated over
10 200 kV, these lines are subject to FERC jurisdiction and regulations that
11 govern their planning, operation, and maintenance. The lines operate at the
12 highest voltage on the DESC system.

13 In addition, the Company placed into service 389 miles of 115 kV
14 lines. These lines, although not under FERC jurisdiction for certain elements
15 of operation and maintenance, do come under the FERC planning guidelines
16 as it relates to system loading conditions or, as referred to previously in my
17 testimony, System Operating Limitations (“SOL”). These 115 kV lines
18 interconnect with 230 kV lines in various Company substations where
19 transformers reduce voltage and circuit breakers and switches can isolate
20 faults on the system. Finally, 115 kV lines typically serve existing and new

1 industrial customers and also serve distribution substations for
2 neighborhoods and communities.

3 As mentioned previously, switchyards and substations are the points
4 of intersection for these lines, and in some instances, serve as direct feeds
5 into industrial customer infrastructure. Twenty-nine substations were
6 constructed that either connected 230 kV and 115 kV lines or served as feeder
7 points into industrial customers or residential neighborhoods due to growth
8 in communities served by the Company. Each of these substations contain
9 high voltage equipment such as switches, banks, transformers, circuit
10 breakers, taps, relaying motor controls, Supervisory Control and Data
11 Acquisition (“SCADA”), communications, security, environmental
12 protection and, in some instances, cyber-security protection. They are
13 designed to safely and reliably deliver energy for distribution to customers
14 while regulating voltage, providing fault protection, and providing capacity
15 to meet the needs of diverse, growing load centers within the Company’s
16 service territory.

17 In regards to solar, fourteen substations have been planned, designed,
18 and constructed to provide interconnection with solar facilities that will result
19 in a total of 975 MW by winter 2020. DESC has been a leader in integrating
20 solar onto its system. Current installed solar is 864 MW. The only generator

1 on DESC's system that generates more electricity than combined solar, from
2 a capacity amount, is V.C. Summer Nuclear Station, and DESC receives only
3 two-thirds of its 975 MW. Solar developers pay for DESC facilities
4 associated with these solar generators, but the same level of planning,
5 engineering, and project management during construction is critical.

6 **Q. CAN YOU DESCRIBE SPECIFIC EXAMPLES OF PROJECTS**
7 **UNDERTAKEN TO MEET CAPACITY NEEDS DURING THE TEST**
8 **YEAR?**

9 A. An example of such a project is the **AMWilliams to Cainhoy**
10 **Transmission Project**, which was completed in 2019. Because of load
11 growth in Charleston and Mt. Pleasant, the planning criteria required the
12 construction of the new 230 kV/115 kV Cainhoy Substation as well as
13 twenty-five miles of new or rebuilt 230 kV and 115 kV transmission lines
14 crossing both the Wando and Cooper Rivers and bringing power into
15 growing areas of Mt. Pleasant and the City of Charleston. Several miles of
16 the construction required matting so as not to disturb marsh grass and barges
17 to erect structures in the rivers. Despite difficult and complex permitting
18 requirements, the substation and lines were constructed on budget and on
19 time while remaining environmentally compliant. While necessary to
20 comply with FERC contingency planning criteria due to load growth, this

1 project also hardened the transmission system in a high growth, coastal
2 corridor by replacing existing, highly vulnerable wooden structures with
3 steel monopoles that can endure wind speeds up to 150 mph.

4 (Photos begin on the following page)

1 **Photo 5: Williams to Cainhoy Line Construction**
2 **(During Construction, Looking West from the Cooper Crossing)**
3



4 **Photo 6: Williams to Cainhoy Line Construction**
5 **(Post-Construction, Looking East Towards the Cooper Crossing)**
6
7
8



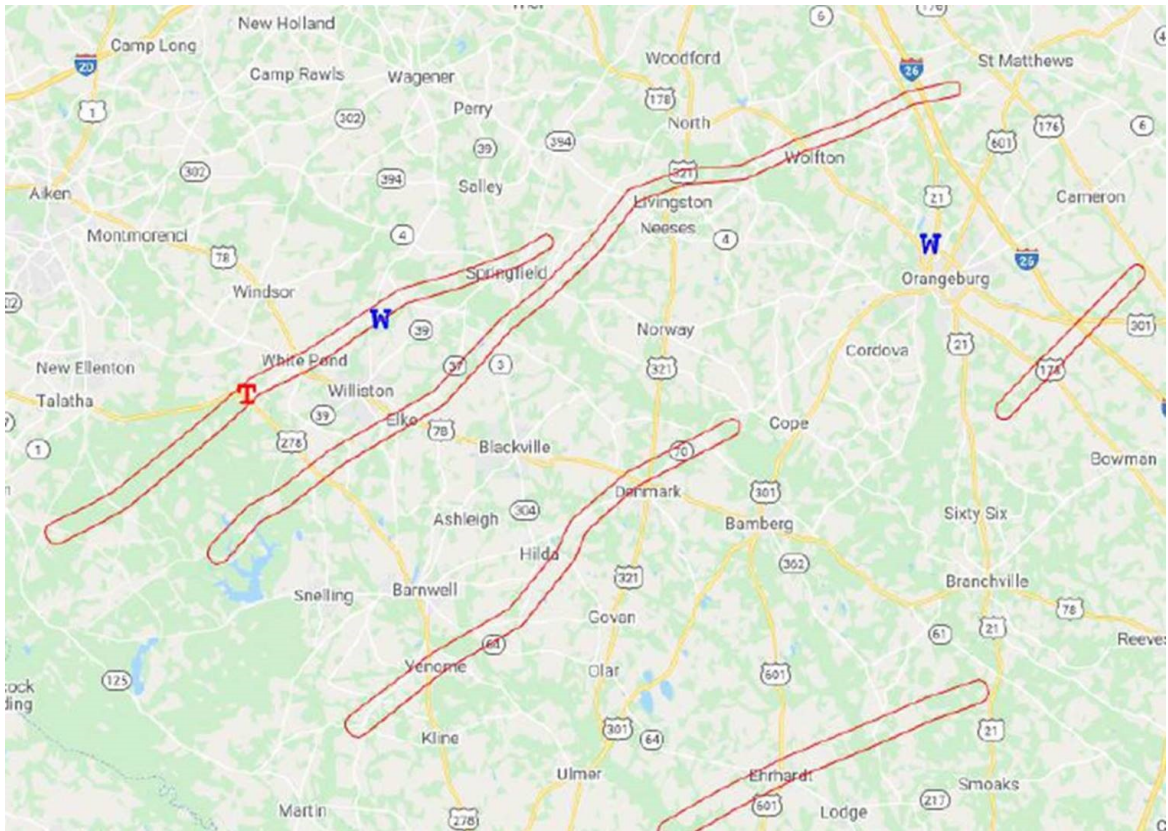
1 **Q. YOU MENTIONED BENEFITS FROM THESE PROJECTS DUE TO**
2 **GRID HARDENING. WAS THERE EVIDENCE THAT CUSTOMERS**
3 **BENEFITED FROM GRID HARDENING DURING THE TEST**
4 **YEAR?**

5 A. Yes. Transmission reliability typically determines ten to fifteen
6 percent of customer SAIDI. The Company's Transmission Planning
7 Department plans for such reliability by modeling system growth and
8 recommending system improvements to ensure reliability in areas of its
9 system most prone to outage events. Weather in the form of wind-blown
10 trees from hurricanes and tornadoes or ice accumulation from winter storms
11 is the greatest risk to our transmission system. For that reason, grid hardening
12 is key to improving transmission reliability. The most common form of grid
13 hardening DESC has utilized has been to change out wooden transmission
14 poles to self-supporting steel monopoles as was done in the AMWilliams to
15 Cainhoy Transmission Project. The steel monopoles are stronger and
16 provide greater wind loading conditional up to 150 mph.

17 In April of 2020, the state of South Carolina experienced a historic
18 on-set of tornadic activity. As these cyclones moved west to east across the
19 Company's service territory, they provided a clear test of the Company's grid
20 hardening efforts. The map below depicts various tornadic paths through

DESC's service area. With some instantaneous wind speeds of 135 mph, these storms left a path of great devastation.

Graph E: Paths of April 2020 Tornadoes



Both wooden transmission structures and self-supporting steel structures were in the path of the tornadoes. The next two pictures show the effect of the tornadoes on wooden structures. No pictures were taken of the effect on the self-supporting steel structures because there was not any to show. The tornadoes did not damage them.

1

Photo 7: Damaged Wooden Structures



2

3

4

Photo 8: Damaged Wooden Structures

5



6

1 **Q. CAN YOU PROVIDE ANOTHER SPECIFIC EXAMPLE OF A**
2 **PROJECT UNDERTAKEN TO MEET CAPACITY NEEDS AND**
3 **IMPROVE RELIABILITY DURING THE TEST YEAR?**

4 A. Yes. Another example of a combined capacity expansion/grid
5 hardening for reliability is **Yemassee to Burton 115 kV #2 and #3 Lines**
6 with distribution underbuild, which replaced the Yemassee to Burton #2 115
7 kV transmission line. In this project, DESC rebuilt the existing
8 approximately 70-year-old Yemassee to Burton #2 115 kV wooden
9 transmission line as a modern double circuit line with a distribution line on
10 the same structures. The rebuild covered 22 miles of environmentally
11 sensitive right-of-way traversing the ACE Basin.

12 Six distribution substations are fed from this line, Yemassee Central,
13 Gardens Corner, Grays Hill, Marine Corps Air Station, Burton Central, and
14 Seabrook Solar. Unfortunately, this line was one of the poorest performing
15 transmission lines on the DESC transmission system. With distribution
16 circuits underbuilt on this transmission line, reliability was even poorer.

17 By double circuiting the line and replacing its vulnerable wood
18 structures with steel, the substations can be connected to either line #2 or line
19 #3, limiting their exposure to outages. This rebuild also increased the

1 number of the transmission feeds into Beaufort, home of the Marine Corps
2 Air Station and the Marine Corps Recruit Depot, from three to four.

3 Challenges related to this project were numerous creek crossings, as
4 well as crossing the Whale Branch marsh and river headed into Beaufort. In
5 addition, there were many times of the year when the line could not be taken
6 out of service without violating NERC reliability criteria for the transmission
7 system. For that reason, construction was limited to the months of March
8 through May and September through November. Even then, construction
9 was subject to being halted on any given day in case of the loss of a major
10 generation station or major transmission line elsewhere on DESC's system.
11 Furthermore, the construction had to be phased to keep the six substations
12 energized at all times. This required expert coordination on a daily basis.

13 There were two major accomplishments related to this project. First
14 and foremost, on the rebuilt sections, there have been zero transmission or
15 distribution outages. In addition, by engaging property owners in the ACE
16 Basin and marshalling the resources of environmental advocates such as
17 Ducks Unlimited, DESC was able to relocate the Yemassee-Burton 115 kV
18 #2 line from the Old Sheldon Church Road to a private right-of-way. This,
19 in turn, will allow for the removal of DESC transmission structures from the
20 side of Old Sheldon Church Road and improve the efforts of local

landowners and state-wide stakeholders to have the roadway considered for National Scenic By-way status—one of only five in South Carolina. Thus, DESC demonstrated collaboration that has increased reliability by grid hardening and also left the surrounding ACE Basin better than the Company found it when embarking on this project.

Photo 9: Yemassee-Burton



Other recent load related transmission projects include the following:

1 **Sewee 115/23 kV Substation, Fold-In & Tie to CEPCI.** Working
2 in collaboration with Central Electrical Power Cooperative, DESC received
3 a new point of service into its Sewee Substation near the intersection of
4 Highway 17 and Lieben Road in Mt. Pleasant, South Carolina to improve
5 reliability and accommodate the growing energy needs within this area.

6 **Saxe-Gotha Industrial Park, 115-23 kV.** DESC constructed this
7 new substation to meet the growing electric demand in Cayce, South
8 Carolina. This area is poised for developing residential growth along the
9 12th Street corridor near Interstate 77 and is already home to Amazon and
10 Nephron Pharmaceuticals.

11 **Gills Creek 115-23 kV and Fold-In.** DESC constructed a new
12 substation off Rosewood Drive to serve growing residential and commercial
13 customers down Devine Street and Garners Ferry Road. This substation
14 contains a new 28 MVA transformer and three 23 kV breakers.

15 **Q. CAN YOU DESCRIBE SPECIFIC EXAMPLES OF TRANSMISSION**
16 **PROJECTS UNDERTAKEN TO SUPPLY NEW OR EXPANDING**
17 **INDUSTRY IN SOUTH CAROLINA?**

18 A. Yes. DESC supports economic growth in South Carolina and job
19 creation by working closely with economic developers to timely provide the

1 necessary electrical infrastructure for both expansions and initial industrial
2 locations. Examples of this effort are as follows:

3 **Mercedes-Benz Vans 115 kV Substation Construction and 115 kV**

4 **Fold-In.** During the test year, DESC built a new DESC-owned substation in
5 Ladson, South Carolina and installed two 115/13.8 kV, 37 MVA
6 transformers to serve the Mercedes-Benz Vans manufacturing facility. The
7 work also involved a fold-in of the nearby Pepperhill to Summerville 115 kV
8 #2 transmission line.

9 **Argos 115-13.8 kV Substation.** DESC relocated the 115 kV #1 tap
10 serving Argos Cement in Harleyville to accommodate a plant expansion,
11 built a new customer substation, Argos Cement Substation #3, and then
12 installed a new 115 kV tap to the newly constructed substation.

13 **Jushi 115-13.8 kV Customer Substation.** DESC relocated an
14 existing 115 kV line and constructed a temporary line for a new industrial
15 customer, Jushi, to utilize during construction. The customer is a new
16 manufacturer of fiberglass material located in the Pineview Industrial Park
17 in lower Richland County. Concurrently, DESC constructed a new customer
18 substation and a 115 kV fold-in with redundancy to serve this customer's
19 manufacturing plant.

1 **Hugh Leatherman 115-13.8 kV Substation.** DESC is designing and
2 engineering a new 115 to 13.8 kV substation to serve the Hugh Leatherman
3 shipping terminal at the South Carolina State Ports Authority in Charleston.
4 This new shipping terminal is expected to boost port capacity by fifty
5 percent. DESC will also construct a new 115 kV tap to feed this substation,
6 necessary for additional cranes, buildings, high mast lighting, and other
7 electrical supporting infrastructure.

8 **Q. PLEASE DESCRIBE THE TRANSMISSION ASSETS**
9 **CONSTRUCTED SINCE THE 2011 TEST PERIOD THAT WERE**
10 **PLANNED WITH THE CONSTRUCTION OF V.C. SUMMER UNITS**
11 **2 AND 3.**

12 A. When construction of V.C. Summer Units 2 and 3 was proposed, the
13 Company performed planning studies on its system to identify the
14 transmission upgrades that would be required to incorporate this generation
15 source onto its system and to link generation resources to customer load
16 centers throughout its system. Those studies showed that a major
17 strengthening of DESC's transmission system was needed to move power
18 from the northern division of its system to the southern division. The
19 backbone of DESC's transmission system are the lines from Jenkinsville,
20 where our largest generation unit is based, into Columbia, and then down to

1 the coastal areas of Charleston and Beaufort. Generation resources on our
2 system are largely concentrated in the northern division. The reasons for this
3 are environmental issues, land use restrictions and limitation on natural gas
4 availability in most coastal areas. In addition, rapid growth in the I-77
5 corridor north of Columbia, and in the Lake Murray and Lexington areas,
6 indicated the need for additional strengthening and additional capacity for
7 the transmission system feeding power into those areas. Also, DESC was
8 concerned about the age of many of the structures that formed part of the
9 transmission system that served as the north-south backbone of its system.
10 Many were wooden H-Frame structures and many were reaching the end of
11 their useful lives. They posed both reliability and resiliency problems for the
12 system going forward, were increasingly expensive to maintain and would
13 need to be replaced under any scenario.

14 In studying the needs of the system in light of the nuclear project, the
15 Company identified the value in expanding and hardening its core
16 transmission system by constructing or reconstructing 376 miles of 230kV
17 and 115kV lines and constructing a new St. George Switchyard and Saluda
18 River Substation. As a result, the Company entered into an EPC contract with
19 Pike Electric for the work.

1 Combining these upgrades into a single project greatly reduced costs.
2 It created economies of scale in procurement and allowed for the efficient
3 use of crews, material, equipment, and laydown yards. Mobilization and
4 demobilization costs were minimized. Having a broad scope of work
5 allowed Pike Electric to shift crews from one part of our system to another
6 on short notice without undue loss of efficiency or schedule. This flexibility
7 was important to cost control and construction efficiency. On days of high
8 energy delivery during seasonal loading demand periods, or when there were
9 transmission or generation contingencies like the loss of a major transmission
10 line or large generating unit, construction had to cease at once in certain
11 locations to eliminate risk and preserve system integrity. Because Pike
12 Electric was able to work multiple lines as a single project, it could keep
13 crews in the field year round and rotate them away from constrained lines on
14 a seasonal basis. When contingencies occurred on the system, Pike Electric
15 could shift crews to work on unaffected lines on short notice. This flexibility
16 to respond to conditions on the system reduced downtime, increased
17 efficiency, and lowered costs for customers. It was a result of making all of
18 these upgrades as a single project.

19 We also made this project more cost effective by replacing older
20 transmission lines that were at the end of their useful lives at the same time

1 that we added new capacity. Many of the lines we replaced were older
2 wooden construction that posed increasing reliability and resilience problems
3 and were expensive to maintain. Replacing them was particularly beneficial
4 for customers because they were a critical part of our system's north-south
5 transmission backbone.

6 All but six miles of the 376 miles of new transmission line Pike
7 Electric installed were installed in existing transmission rights of way. With
8 crews in those corridors and a supply chain in place to support them, we
9 created tremendous cost savings for customers by rebuilding older lines as
10 part of the same project.

11 The older lines were typically rebuilt on the same steel monopoles as
12 the new lines—double circuit lines. Putting two transmission lines on a single
13 monopole dramatically reduces construction cost. This configuration also
14 frees up space on the right of way because even with two lines, a single
15 monopole configuration is much more compact than a wooden H-frame that
16 typically carries only one line. Opening up the right of way increases the
17 separation of the transmission lines from trees and other vegetation on the far
18 edge of the right of way and creates more room for maintenance and repair
19 crews to work. This increases reliability and resiliency and reduces safety
20 risks for crews working the lines in storms or otherwise. At the same time,

1 in rebuilding the existing lines, we replaced the older conductors with
2 stronger, higher capacity modern conductors, which created yet more
3 capacity and resiliency in the lines themselves.

4 Doing all this work as part of a single system-wide upgrade was the
5 most efficient means of producing savings and at the same time improving
6 system reliability. It allowed our transmission group to design and deliver a
7 comprehensive upgrade to the capacity, reliability, and resilience of our
8 transmission system through a single project. We achieved economies of
9 scale in design, procurement, and staffing of the project, and minimized
10 permitting, mobilization, and demobilization costs. The project was
11 delivered on time and on budget. I cannot overstate the value of the savings
12 and efficiency that this approach created.

13 **Q. WOULD THESE UPGRADES HAVE BEEN NECESSARY**
14 **REGARDLESS OF WHETHER THE GENERATION HAD BEEN**
15 **CONSTRUCTED?**

16 A. Yes. Through this project, the Company constructed 376 miles of 230
17 kV and 115 kV lines along with a substation, a switchyard, switchgear
18 upgrades and other assets. Looking at the system today, utilizing double
19 contingency FERC planning criteria, numerous 230 kV lines, 115 kV lines
20 and transformers would be thermally overloaded or highly loaded today

1 without the resulting system upgrades. They would require immediate
2 projects to rebuild or improve them.

3 **Q. CAN YOU QUANTIFY THE LINES AND OTHER ASSETS THAT**
4 **WOULD BE OVERLOADED OR HIGHLY LOADED UNDER FERC**
5 **CRITERIA?**

6 A. Yes. Under an N-1 Scenario (first contingency modeling) the System
7 Impact Study (“SIS”), through power flow analysis, identified three 230 kV
8 lines and eleven 115 kV lines that would be loaded at greater than 90%.
9 Similarly, four 115 kV lines and one 230/115 kV transformer would be over
10 100% thermally loaded.

11 Under an N-1-1 and N-2 (double contingency power flow analysis),
12 utilizing SIS criteria, nine 230 kV lines and five 115 kV transformers would
13 have been at greater than 90% thermally loaded, while four 230 kV lines,
14 fifteen 115 kV lines, and seven 230/115 kV transformers would have been
15 thermally overloaded by greater than 100%.

16 Stated another way, absent these upgrades for system integrity, 97
17 miles of 115 kV and 124 miles of 230 kV would have been heavily loaded
18 and approximately 180 miles of 115 kV and 171 miles of 230 kV would have
19 been overloaded, a total of 572 miles. In addition, 224 MVA of transformers

1 would have been heavily loaded and 2,128 MVA of transformers would have
2 been overloaded.

3 Use of FERC-approved planning criteria for grid interconnection and
4 reliability, based upon accepted double contingency scenarios, confirms that
5 the 376 miles of transmission lines originally associated with V.C. Summer
6 Units 2 and 3 are used and useful, and as energized assets on the DESC
7 transmission system, they provide reliability, resiliency, and capacity for
8 either industrial or residential growth. Furthermore, by working contingently
9 as one project, the EPC methodology provided an extremely proficient and
10 cost-effective means of uprating the DESC transmission grid, as opposed to
11 the expenses of performing the work piecemeal as warranted by individual
12 line segment conditions.

13 **V. DISTRIBUTION IMPROVEMENTS**

14 **Q. HAVE INVESTMENTS IMPROVED RELIABILITY ON THE DESC**
15 **DISTRIBUTION SYSTEM?**

16 **A.** Yes. DESC continuously invests in its distribution assets in order to
17 serve new customers and constantly improves resiliency and reliability by
18 replacing distribution equipment that has reached the end of its ability to
19 serve customers safely, reliably and resiliently. Since the close of the 2011
20 test year, DESC has installed approximately 53,000 new or replacement
21 distribution transformers and approximately 3,100 miles of new or

1 replacement distribution lines. Before accounting for depreciation and other
 2 offsets, since the close of the 2011 test year, DESC has invested \$1.1 billion
 3 in expansions and improvements to the distribution system. These
 4 improvements have been necessary for DESC to provide the safe, reliable,
 5 and economical delivery of electric service to its customers. They have been
 6 part of the how it has been possible for the Company to achieve the level of
 7 safety, reliability, and resilience I discussed earlier in my testimony.

8 **Q. IS DESC'S SERVICE TERRITORY CONTINUING TO GROW?**

9 A. Yes. We have added over 80,000 electric customer accounts since the
 10 close of 2011, an increase of approximately 12%. Customer growth has been
 11 concentrated in the Interstate 26 corridor from Charleston to Summerville
 12 and beyond, on the Charleston peninsula itself where redevelopment of large
 13 areas is occurring, in Lexington County, downtown Columbia, northeast
 14 Columbia, Cayce, West Columbia, Lake Murray, and North Augusta.
 15 Growth on the system is shown in Table E.

16 **Table E: Annual Customer Growth Since 2012**

	Growth Since Last Rate Case		
	Customers 1/1/2012	Customers 12/31/2019	Total
<u>Columbia/Lexington</u>	250,246	275,479	10.08%
<u>Charleston/Summerville</u>	218,702	252,593	15.50%
<u>Aiken</u>	38,487	41,153	6.93%
<u>N. Augusta</u>	12,093	13,721	13.46%

1 DESC's DSM programs and increased energy efficiency standards for
2 appliances, lighting and construction have reduced load growth on the system
3 generally. But meeting the needs of new customers in rapidly growing areas
4 still requires investment in new and expanded distribution and transmission
5 as stated above.

6 **Q. HAS THE COMPANY MADE ANY TECHNOLOGICAL UPGRADES**
7 **TO ITS DISTRIBUTION SYSTEM?**

8 A. Yes. The Company is continually investing in new distribution
9 technology to better protect its system and serve its customers. Since 2012,
10 DESC has installed 286 SCADA switches upon its distribution system for a
11 total cost of \$9.8 million. These switches directly notify our distribution
12 control centers of faulty current due to external damage or failure and allow
13 for the re-routing of power flow either automatically or remotely when
14 problems occur. They allow our control room to precisely locate and isolate
15 a fault on the system remotely, without having to wait for line crews to arrive
16 to operate manual switching in the field. This minimizes the number of
17 customers who are subject to outage and can mean the difference between a
18 handful of customers being out due to a single fault on the distribution system
19 as opposed to hundreds of customers. The SCADA investment provides us
20 with an extremely valuable asset that allows us to monitor the electric

1 distribution system in real time and respond quickly and effectively to
2 customer outages.

3 In addition, the Company has embarked upon a three-year project to
4 install Advanced Metering Infrastructure (“AMI”). This technology will
5 improve customer service by allowing the Company to remotely
6 communicate with meters to receive outage information. It also allows for
7 remote connect and disconnect, thus eliminating the need to roll trucks to
8 perform such functions on customer premises. Finally, once installed, these
9 meters have the potential to provide customers with extensive historical and
10 on-demand information regarding their electrical usage to allow them to
11 make wise energy choices.

12 **VI. DESC’S INVESTMENTS IN CUSTOMER SERVICE**

13 **Q. WHAT IS THE STRATEGIC FOCUS OF DESC’S CUSTOMER**
14 **SERVICE GROUP?**

15 A. The strategic focus for the DESC Customer Service group is
16 continuing to improve our customers’ experience by reducing customer
17 effort (a key driver of customer satisfaction), training and engaging
18 employees, and utilizing customer insights and data analytics to guide
19 decisions. While customer expectations continue to increase and evolve, we
20 know through surveys as well as other listening posts (social media, calls,
21 emails) that customers want self-service options and proactive, personalized

1 communications that make it easy to do business with us. Our vision to create
2 a consistent, effortless customer experience has been the driver for
3 technology improvements during the last several years.

4 **Q. WHAT STEPS HAS DESC TAKEN TO MAINTAIN A HIGH LEVEL**
5 **OF CUSTOMER SERVICE?**

6 A. **Interactive Voice Response (“IVR”) System Upgrades.** Recent
7 IVR system improvements have included intelligent menus that predict why
8 customers may be calling us and provide options based on the likely purpose
9 for the call. The IVR authenticates the customer’s account through telephone
10 number recognition and captures account status such as a payment due,
11 likelihood the customer is experiencing an outage, and a scheduled
12 disconnect on the account. “Say or Press” menus allow the customer to speak
13 or use the keypad, benefiting smartphone users. In addition, Spanish
14 speaking menus are now offered. In 2019, 44.9% of customer calls were
15 successfully managed through the IVR. Our IVR overall satisfaction rating
16 through June 2020 is 8.50 on a 10-point scale.

17 **Website Enhancements.** Conversion to a responsive design (ability
18 to adapt to various screen sizes whether on a mobile, desktop, or tablet
19 device) has allowed for easier website usability across all devices. Additional
20 enhancements to self-service options have made it easier for customers to

1 make payment arrangements and establish, transfer or turn off service.
2 Completed security upgrades further protect customer account data.

3 **Mobile App.** The Company's mobile app launched in October 2019,
4 making it even easier for customers to do business with us. The mobile app
5 provides easy account access using biometric log-in capability and full
6 mobile website functionality to include service orders, bill and payment
7 options as well as usage analysis. Reporting an outage now takes only
8 seconds using the mobile app. The mobile app allows for proactive push
9 notifications informing customers when their bill is ready, payment
10 reminders, and payment received as well as other notifications. Through June
11 2020, 82,342 customers have downloaded the mobile app.

12 **Lowering Customer Effort.** IVR and website enhancements along
13 with the mobile app have contributed to substantial satisfaction among our
14 high frequency callers (customers that call the company ten times or more
15 per year). Proactive communications using email and/or mobile app push
16 notifications notify customers of payment due, scheduled disconnects,
17 payment received, and disconnects canceled, eliminating the need for the
18 customer to call us, lowering customer effort and increasing satisfaction. As
19 a result, customer representative answered calls from high frequency callers

1 have decreased 68% since 2015 (comparing January–June 2015 to January–
2 June 2020).

3 **Builder Portal.** Beginning this fall, new functionality will allow key
4 residential builders to better manage electric and gas service requests for new
5 construction through a newly designed web portal. This self-service option
6 allows builders to easily submit requests with a pin drop on a map as well as
7 track progress of requests through a dashboard. Builders will receive
8 proactive notifications of any issues that arise that may impact fulfilling
9 service requests. These notifications provide details about issues the builder
10 may need to resolve or additional steps the Company may need to
11 take. These enhancements eliminate effort for our customers and improve
12 the experience with our Company.

13 **Enhanced Outage Experience.** Customers now have multiple
14 options to communicate with DESC during a power outage (mobile app,
15 website, IVR, SMS text, and customer representatives). As of June 2020,
16 approximately 75% of customer power outages were reported through self-
17 service channels, greatly reducing the time and effort required of customers
18 and reducing costs.

19 During an outage, customers can also access our online electric power
20 outage map to check outage status. The improved design is accessible via the

1 mobile app, responsive on multiple devices, interactive, and includes county
2 and region views. The new functionality even allows a web storm curtain to
3 automatically display on the DESC public websites (full site and mobile)
4 when there is a storm. It allows proactive web messaging and includes a link
5 for customers to report an outage or check status.

6 The Company has also improved an internal application to identify
7 customers impacted by a planned outage, work in progress, and tree trimming
8 using GIS mapping functionality. Customers receive proactive notifications
9 via email or postcard in advance of work activities that may impact electric
10 service.

11 **Service Satisfaction Metrics.** As a result of these investments,
12 customer satisfaction metrics remain high. Transactional customer surveys
13 measure satisfaction with our website, telephone calls with a customer
14 service representative, IVR, and field services. The overall transactional
15 customer satisfaction rating is 8.50 on a 10-point scale.

16 As a result of the SCANA and Dominion Energy merger, the
17 Commission requires DESC to provide Service Quality Standards reporting
18 on a quarterly basis. Through the first quarter of 2020, the Company's scores
19 measuring overall customer impressions have improved in seven of the seven
20 metrics reported. Satisfaction metrics related to the quality of calls with our

1 customer service representatives (measured through external research
2 studies) have improved from already high ratings to 8.99 and higher on a 10-
3 point scale. These results mirror our internal transactional survey satisfaction
4 rating of 9.20 through June 2020.

5 External research studies through Market Strategies have also shown
6 steady improvements in customer engagement scores since nuclear
7 abandonment.

8 **Customer Assistance.** In addition to technology investments to
9 improve customer experience, the Company remains committed to serving
10 low-income customers, disabled customers, veterans, seniors and those
11 medically dependent on electricity through our customer assistance and
12 community outreach efforts.

13 In 2019, the Company participated in over 200 community outreach
14 events and over 50 events prior to COVID-19 in 2020. Along with over 180
15 community partners, we provided customers with financial assistance
16 availability, energy assistance tips, and easy ways to do business with us.

17 In May of 2020, the Company introduced **EnergyShare** in South
18 Carolina. EnergyShare provides utility bill assistance to qualifying low-
19 income customers. A Dominion Energy corporate contribution of \$750,000
20 in program funding was provided in 2020 to establish the program, which is

1 administered by the SC Department of Administration Office of Economic
2 Opportunity.

3 The Company offers **WebPledge**, an online web application, to
4 agency partners to assist with online pledge/voucher payments to assist
5 DESC customers. WebPledge allows customer assistance funds to flow from
6 agencies to our customers' accounts, quickly attending to customer financial
7 needs.

8 During the COVID-19 pandemic, the Company has assisted
9 customers in need of financial assistance working with community action
10 agencies and other non-profit organizations. From April 30 to June 30, 2020,
11 3,698 pledges totaling over \$2.5 million in assistance have been received for
12 DESC customers.

13 **Customer Call Volume.** An excellent indicator of customer effort is
14 customer call volume. By reducing call volume, we reduce customer effort,
15 leading to improved satisfaction. Eliminating the need for a customer to call
16 us by improving processes that drive call volume, providing proactive
17 communications, and offering self-service options improves the overall
18 customer experience. Comparing year-end 2019 with year-end 2015, call
19 volume has decreased 26%, a reduction of approximately 600,000 calls,
20 made even more impressive given strong customer growth in South Carolina.

1 **Conclusion.** Over the past several years, DESC has improved
2 customer service, reduced costs and improved communications with
3 customers by making it easier for customers to do business with us. Excellent
4 system reliability, improved technology, well thought out tools and
5 processes, and dedicated employees all contribute to our high level of
6 customer service.

7 **Q. PLEASE EXPLAIN THE COMPANY'S DECISION TO CLOSE ITS**
8 **REMAINING FIVE BUSINESS OFFICES.**

9 A. In July of 2020, DESC announced that the remaining five business
10 offices that were open pre-COVID-19 will remain closed permanently. In
11 making that decision, we carefully evaluated the experience of industry
12 peers, confirmed that customers had an array of other options for doing
13 business with us, and compared the relative value of the talents of employees
14 that have traditionally operated the business offices against other options.
15 Ultimately, we decided that redeploying their efforts to our Customer
16 Assistance Team; Smart Meter and expanded DSM Programs; and traditional
17 customer service roles was a higher priority and better use of their skills for
18 customers. We made that decision prior to filing this rate case to be candid
19 with the Commission and ORS in this proceeding as well as to give the

1 employees affected the best opportunity to find permanent new roles in the
2 Company.

3 **VII. VEGETATION MANAGEMENT ACCRUAL**

4 **Q. PLEASE DISCUSS THE PROPOSED VEGETATION**
5 **MANAGEMENT ACCRUAL ACCOUNT.**

6 A. Vegetation accounts for the highest number of outages on the DESC
7 distribution system. As previously discussed, the key to effective vegetation
8 management is disciplined adherence to a regular cycle of work. For
9 example, DESC's most effective means of maintaining its transmission
10 rights-of-way is the backpack spraying of selective herbicides on the floors
11 of its rights-of-way. Utilizing this approach, DESC targets invasive species
12 only, while allowing for the beneficial growth of grasses, forbs, and briar
13 berries that serve to carpet the rights-of-way and prevent infestation of
14 unwanted species such as volunteer pine and gums. This approach works
15 only if it is implemented consistently and in a sustained way. When it is, the
16 costs are lower and the results are better. But if the cycle is neglected, the
17 benefits are lost. The same is true for urban work. If the cycles are
18 maintained, then vegetation can adapt, fill in gaps and be trained to grow in
19 ways that are safe and beneficial. If the cycle is neglected, restoring the right
20 of way is harsher and more disruptive.

1 The Company proposes to establish a vegetation management accrual
2 to provide a predictable basis for funding a multi-year vegetation
3 management program. The effect would levelize vegetation management
4 expenses over an average five-year vegetation management cycle. Actual
5 vegetation management expenses would be applied against the accrual. Any
6 difference between collections and expenses, positive or negative, would
7 carry over year to year. Vegetation management expenses can vary annually
8 depending on the difficulty of the rights-of-way being treated in the cycle
9 that year. Storm restoration emergencies anywhere on the East Coast can
10 divert vegetation crews to storm work, shifting work and costs on our system
11 from one year to the next. The accrual serves to mitigate these year-to-year
12 cost fluctuations and provides for more efficient planning and staffing of
13 these activities.

14 During the test year, the Company spent approximately \$24.1 million
15 on vegetation management and, based on upcoming cutting cycles and
16 current pricing from contracts, we project this amount to increase by \$3.5
17 million on average over the next five years. This results in a vegetation
18 management expense of approximately \$27.6 million, which the Company
19 requests to be reflected in rates. The increase above test year spending,
20 however, is only \$3.5 million.

1 **VIII. STORM DAMAGE RESERVE**

2 **Q. PLEASE DISCUSS THE PROPOSAL TO RESUME COLLECTION**
3 **FOR THE COMPANY'S STORM DAMAGE RESERVE.**

4 A. In Order No. 1996-15, the Commission authorized the
5 implementation of a storm damage reserve. Pursuant to that authorization,
6 collections under the rider established a reserve, and incremental storm
7 damage remediation and restoration costs that exceeded \$2.5 million
8 annually were eligible to be applied against the reserve. Collections under
9 the storm damage rider were suspended pursuant to Order Nos. 2010-471 and
10 2012-951. Since the suspension of collections under the rider, the Company
11 has exhausted its previous reserve balance and has deferred approximately
12 \$43.9 million, as of June 30, 2020, of incremental storm damage remediation
13 costs. As Company Witnesses Ms. Griffin and Mr. Coffey discuss, DESC
14 proposes amortizing this amount into rates over five years, resulting in an
15 amortization expense of approximately \$8.8 million per year.

16 In addition to amortizing past balances, DESC is also proposing to
17 reinstate the collection for the storm damage reserve going forward. As
18 noted above, collections have been suspended since the effective date of
19 Order No. 2010-471. Reinstatement will allow the cost of storms to be
20 spread over multiple years and make it less likely that future storms would
21 trigger rate proceedings. The request is to reinstate collections at the five-

1 year average storm damage cost experienced from 2014 to 2019. The
2 resulting increase in expense is \$9.8 million per year.

3 **IX. TURBINE MAINTENANCE EXPENSE ACCRUAL**

4 **Q. PLEASE DISCUSS THE COMPANY'S REQUEST REGARDING**
5 **THE TURBINE MAINTENANCE EXPENSE ACCRUAL.**

6 A. Turbines create the mechanical energy that is used to generate
7 electricity. While in operation, the turbines in our combined cycle, coal and
8 coal/natural gas-fired units rotate at high speeds under heavy loading. If
9 these turbines experience a mechanical failure, the safety of our personnel
10 can be put in jeopardy, the reliability of the system can be compromised, and
11 the physical damage to the unit itself can be extensive and difficult to repair.

12 Specific maintenance schedules exist for each steam turbine unit
13 based on factors such as numbers of stops and starts, hours of operation, and
14 loading levels since the last maintenance cycle. Following the turbine
15 maintenance schedule is critical to maintaining the reliability of DESC's
16 generation fleet and preventing destructive failures. The principal driver of
17 turbine maintenance expense today is our fleet of seven large frame gas
18 turbines located in combined cycle units. While these gas turbines have low
19 capital costs and non-fuel operating costs, they must be disassembled,
20 inspected, refurbished or repaired on a regular cycle to ensure their continued
21 safety and reliability.

1 **Q. HOW DOES VARIABILITY IN TURBINE MAINTENANCE**
2 **EXPENSE AFFECT THE RATEMAKING PROCESS?**

3 A. The amount of turbine maintenance work varies every year based on
4 maintenance cycles and work plans. For that reason, the turbine maintenance
5 expense in any given test year is unlikely to provide an accurate measure of
6 the average turbine maintenance expense over the life of the cycle. In Order
7 No. 2005-2, the Commission authorized the Company to compute the
8 anticipated cost of turbine maintenance over an eight-year maintenance cycle
9 and reflect that amount as a levelized cost in its retail electric base rates. As
10 Mr. Coffey explains in his testimony, the Commission also allowed the
11 Company to record the difference between the levelized cost and the actual
12 amount of turbine maintenance expense incurred in a regulatory asset
13 account.

14 **Q. WHAT BENEFITS DOES THIS METHOD CREATE FOR**
15 **CUSTOMERS?**

16 A. Leveling turbine maintenance costs over the eight-year maintenance
17 cycle allows the Company to schedule maintenance for maximum efficiency
18 and lowest cost over the maintenance cycle, regardless of how it might
19 otherwise impact the year-to-year budget cycle. It supports entering into
20 favorable, long-term turbine maintenance contracts with third party

1 providers, which DESC has done to further reduce costs and increase
2 predictability. Levelizing costs ensures that the costs reflected in rates match
3 the actual cost of maintenance over that cycle.

4 **Q. WHAT ADJUSTMENT IN THE MAJOR MAINTENANCE**
5 **ACCRUAL IS REQUIRED IN THIS PROCEEDING?**

6 A. DESC has computed the levelized cost of turbine maintenance over
7 the upcoming eight-year cycle from January 1, 2021, through December 31,
8 2028, based on the current turbine maintenance schedule, work plan and
9 pricing. That calculation shows that the turbine maintenance costs reflected
10 in rates in 2011 need to be increased by approximately \$10.6 million to \$29.1
11 million annually to cover actual costs going forward.

12 **Q. WHAT IS DRIVING THIS INCREASE?**

13 A. Since the levelized rate was established, gas has displaced coal as the
14 predominant fuel source on DESC's system. DESC's seven combined cycle
15 gas units are the most efficient gas fired units on its system. Since 2011, they
16 have gone from intermediate load status to baseload status, where they are in
17 almost continuous use day in and day out. This has greatly increased turbine
18 maintenance cost for the system.

19 In addition, the new accrual amount includes the turbine maintenance
20 costs associated with the recently acquired Columbia Energy Center. This

1 combined cycle unit contains two new large frame gas turbines and has a net
2 dependable summer generation capacity of 519 MW. Columbia Energy
3 Center represents a major addition to the combined cycle fleet and a 40%
4 increase in the number of large frame gas turbines on DESC's system.

5 **Q. IS THERE AN OUTSTANDING BALANCE IN THE MAJOR**
6 **MAINTENANCE ACCRUAL ACCOUNT?**

7 A. Yes. The current unrecovered balance in the turbine maintenance
8 account is \$12.0 million. This balance has accumulated over eight years and
9 reflects a cumulative variance from the 2011 forecast of only approximately
10 8% over that time. This unrecovered balance is the result of the same drivers
11 listed above, especially the increased frequency of inspections and
12 maintenance at combined cycle plants due to increased gas usage.

13 **Q. IS THIS TURBINE MAINTENANCE EXPENSE A REASONABLE**
14 **COST OF PROVIDING SERVICE TO CUSTOMERS?**

15 A. Yes. Turbine maintenance represents an investment in the continued
16 reliability of the Company's electric system and in the protection of system
17 assets from failure and potentially catastrophic damage. For that reason,
18 turbine maintenance expense is a necessary cost of providing safe, reliable,
19 and economical service. DESC has relied on the turbine maintenance accrual
20 mechanism to allow it to schedule turbine maintenance in the most efficient

1 and economical way over an eight-year cycle knowing that levelized cost
2 recovery would allow it to do so.

3 **X. TRANSMISSION AMORTIZATION**

4 **Q. PLEASE DISCUSS THE DEFERRED DEPRECIATION AND**
5 **PROPERTY TAX ASSOCIATED WITH THE TRANSMISSION**
6 **UPGRADES UNDERTAKEN AT THE TIME OF THE NEW**
7 **NUCLEAR GENERATION PROJECT.**

8 A. In Order No. 2018-804, the Commission allowed the Company to
9 defer, as a regulatory asset, the ongoing costs associated with the
10 transmission asset upgrades undertaken as a part of the comprehensive
11 project to improve the north-south backbone of our transmission system at
12 the time of the new nuclear generation project. The amounts deferred include
13 the depreciation and property taxes associated with those assets since they
14 went into service. As Mr. Kochems testifies, the deferred amount totals
15 approximately \$47 million. The Company requests that the Commission
16 recognize the amortization of this deferred amount into rates under the terms
17 discussed by Mr. Kochems in his testimony.

18 **Q. ARE THESE DEFERRED AMOUNTS A REASONABLE COST OF**
19 **UTILITY SERVICE?**

20 A. Yes. These deferred costs are costs DESC incurred because it put
21 newly constructed transmission assets into service to benefit customers.

1 They have improved the safety, reliability, and resilience of the system, and
2 customers have benefitted. Their resiliency has minimized outages in recent
3 storms and allowed service restoration to be accomplished quickly and
4 safely. As explained above, without these assets in service, hundreds of
5 miles of transmission lines and multiple transformers would be overloaded
6 today under FERC-approved planning criteria. It is reasonable for customers
7 to be responsible for the cost of operating and maintaining these assets that
8 have benefited them during this time.

9 **XI. CONCLUSION**

10 **Q. WHAT ARE YOU REQUESTING THE COMMISSION TO DO?**

11 A. I am respectfully asking the Commission to recognize the value that
12 DESC provides its electric customers and the hard work and diligence that
13 thousands of employees have put into creating the operating results discussed
14 here. I respectfully ask the Commission to approve the rate relief required to
15 allow us to fund the continued investment in the safe, reliable and economical
16 delivery of electric service to our customers. I specifically request approval
17 of the Vegetation Management Accrual Account and the resumed funding of
18 the Storm Damage Reserve, the adjustment to the Major Maintenance
19 Accrual and the amortization of deferred transmission expenses.

20 **Q. DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?**

21 A. Yes. It does.